NIPER-681
Distribution Category UC-122
May 1993

Status Report

ANALYSIS OF FIELD APPLICATION OF FOAMS FOR OIL PRODUCTION SYMPOSIUM

Project SGP63, Milestone 3, FY93

By Partha S. Sarathi and David K. Olsen

Work performed for
U.S. Department of Energy
Under Cooperative Agreement
DE-FC22-83FE60149

Thomas B. Reid, Program Manager
U.S. Department of Energy
Bartlesville Project Office

DISCLAIMER

IIT Research Institute
NATIONAL INSTITUTE FOR PETROLEUM AND ENERGY RESEARCH
P.O. Box 2128
Bartlesville, Oklahoma 74005
(918) 336-2400

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE

ANALYSIS OF
FIELD APPLICATION OF FOAMS FOR OIL PRODUCTION SYMPOSIUM

By Partha S. Sarathi and David K. Olsen

ABSTRACT

As part of the DOE technology transfer program for fossil energy, a symposium on field application of foams for oil production was held at Bakersfield, Calif., on Feb. 11-12, 1993. The objective of this symposium was to determine the state-of-the-art in field application of foam for oil recovery and to enhance the development of the technology through open discussion of the successes and failures in the application of foam.

As part of the symposium, a six-member panel with expertise in various aspects of field foam application was convened to assess the future of that technology. As a follow-up to the foam symposium, a questionnaire was sent to selected symposium participants to assess industry interest in foam technology and to help determine the role that the DOE should play in nurturing and sustaining this technology. This status report summarizes the panel presentations and discussion, as well as the responses to the questionnaire.

Based on the symposium discussions and the response to the follow-up questionnaire the following conclusions were drawn:

1. Foams have been used in two types of field applications for oil recovery: low volume, inexpensive, near-well treatments to improve injection and production profiles, and large volume, expensive processes for improving sweep efficiency in EOR projects.
2. Foams are technically viable processes for both of these types of field applications.
3. The economics of the process, however, is tied directly to the price of oil. At heavy oil prices of less than $20/bbl, it is unlikely that additional large volumes of surfactant foam sweep improvement projects will be implemented. Even then interest is likely to be minimal among majors due to maturity of existing projects and a rate of return that does not commensurate with the expenses.
4. New projects will continue to be the low-cost steam-foam treatment projects where foam is used to improve injection profiles mostly in cyclic wells rather than steam-foam process where foam is used to achieve in-depth mobility control in steamdrive projects.
5. Beyond the current DOE-industry cost-shared pilots, no major gas-foam pilots are likely to be implemented in the United States due to technical uncertainties, low oil prices, and high operational costs. However, ESSO Canada (Exxon) has started a large gas-foam project in western Canada.

6. The DOE should continue its support for basic research on the use of foam in porous media and sponsor long-duration cost-shared steam-foam projects in different fields to obtain field specific information.

INTRODUCTION

This report is an overview of the panel discussion and participant comments during the DOE/NIPER Symposium on Field Application of Foams for Oil Production, which was held in Bakersfield, Calif., on Feb. 11-12, 1993.

Seventy-two engineers and scientists from seven countries representing major oil companies, independents, service companies, academia, research organizations, and government attended and participated in discussion and panel presentations on the current status of the foam technology. A list of participants is attached in the appendix. The agenda included 13 technical papers and 8 poster presentations. Preprints of technical papers and poster abstracts were compiled and distributed at the symposia. The papers and a summary of the panel discussion are being edited and will be included in the proceedings of the symposium. Response from the participants indicated that the symposium was an overwhelming success and future symposia should be held.

Based on participant's comments and the panel discussion, the following conclusions were observed:

1. Foams have been used in two types of field applications for oil recovery: low volume, inexpensive, near-well treatments to improve injection and production profiles, and large volume, expensive processes for improving sweep efficiency in EOR projects.
2. Foams are technically viable processes for both of these types of field applications.
3. The economics of the process, however, is tied directly to the price of oil. At heavy oil prices of less than $20/bbl, it is unlikely that additional large volumes of surfactant foam sweep improvement projects will be implemented. Even then interest is likely to be minimal among majors due to maturity of existing projects and a rate of return that does not commensurate with the expenses.
4. New projects will continue to be the low-cost steam-foam treatment projects where foam is used to improve injection profiles mostly in cyclic wells rather than steam-foam process where foam is used to achieve in-depth mobility control in steamdrive projects.
5. Beyond the current DOE-industry cost-shared pilots, no major gas-foam pilots are likely to be implemented in the United States due to technical uncertainties, low oil prices, and high operational costs. However, ESSO Canada (Exxon) has started a large gas-foam project in western Canada.
6. The DOE should continue its support for basic research on the use of foam in porous media and sponsor long-duration cost-shared steam-foam projects in different fields to obtain field specific information.

ACKNOWLEDGMENTS

This work was sponsored by the U.S. Department of Energy under cooperative agreement DE-FC22-83FE60149; Project SGP63. The authors wish to thank Dr. A. Strycker and Dr. M. K. Tham of NIPER and Thomas B. Reid of U.S. DOE for their critical reviews. The authors also thank Dr. Syed Mahmood for his assistance in recording the symposium presentation.

FOLLOW-UP ACTION

As a follow-up to the foam symposium, a questionnaire was sent to selected symposium participants to assess the industry interest in foam technology and the role that the DOE should play in nurturing and sustaining this technology. The responses from the participants are summarized as follows:

How Much Interest Does the Industry Currently Have on the Use of Foam to Enhance Oil Recovery? Reasons?

The industry perceives foam as an EOR technology that can be used to harvest a third crop of oil, provided the price is right. Even when heavy oil was selling at $20/bbl, the large volume steam-foam process was only marginally economical. Under current economic conditions, industry has little interest in using foam to correct gravity override problems in steamdrive and improve recovery efficiency. At present, industry uses foam principally to correct steam-distribution problems in cyclic steam stimulation wells.

What is the Greatest Impediment to the Application Of Foam?

Management's operation philosophy hinders the widespread acceptance of foam. In today's economic climate, all companies strive for a low-cost operation—majors will entertain a project only if the payout is less than 60 days and maximize the cash flow. It takes about 6 months to 1 year of foam injection to see any significant increase in oil production, which is too long a time lag for most operators.

Who are the Major Players Currently Using Foam to Improve Recovery?

Steam/Foam:	Mobil, Chevron
CO_2/Foam:	Phillips, ARCO
Hydrocarbon/Foam:	ARCO, ESSO

Some of the success of steam-foam by Mobil and Chevron is due to applications of foam in steamfloods whose ages are early to mid-life. Some majors have learned that middle age to mature steamfloods have too large a void volume (it would take too much surfactant/foam) to affect additional economic oil recovery. There is not much that an operator can economically do with foam for a mature steamflood.

Comments by Authors: (Sarathi and Olsen, NIPER)

Some of the lessons learned from the previous DOE-Industry and industry steam foam projects are shown in Table 1 where the surfactant consumption and cost for chemical for each incremental barrel of oil produced was compiled from Eson and Cooke listing of projects (1989) and calculated (Olsen, NIPER-436, 1989). In some of the cases the cost of incremental oil with foam for steam diversion "advanced technology" was prohibitive, because when the chemical and nitrogen cost for foam generation are added to the cost of steam and lifting costs, the total oil production costs were higher than the crude oil market price.

Several successful "steam-foam process" pilots have been reported (Castanier and Brigham, 1988; Patzek and Koinis, 1988; Yannimaras and Kobbe, 1988; Mohammadi et al., 1989a, b; Eson and Cooke, 1989). In most cases, the steam foam was applied to a mature steamdrive (>10 years of steam injection). An exception to this is the Bishop lease steam foam pilot in Kern River field (Patzek and Koinis, 1988), which had been under active steamdrive for only a year before

TABLE 1 - Analysis of published field applications using steam foam diverters—uses and costs

Ref.[1]	Operator	Field	Sand	Treatment	Surfactant consumption and cost per incremental bbl lb/bbl	Surfactant consumption and cost per incremental bbl $/bbl
Greaser	Getty	Kern River		Slug	0.6	0.49
Farrell	Petro Lewis	Kern Front	-	Slug	2.0	1.80
Doscher	Santa Fe Energy	Midway Sunset	-	Cont.	0.7	0.57
	Conoco	Cat Canyon	-	Cont.	Ineffective surfactant due to high temperature	
	Texaco	San Ardo	-	Cont.	Too small a slug and too short a pilot period	
Palzek	Shell	Kern River	Mecca	Cont.	7.1	5.44
			Bishop	Cont.	15.1	11.58
Mohammadi	UNOCAL	Santa Maria	-	Cont.	8.7	11.75
Mohammadi	UNOCAL	Midway Sunset	-	Cont.	5.8	4.5
Chiang Malito	Petro Lewis	Kern River	-	Semi-cont.	3.3	4.42
Ploeg	Chevron	Midway Sunset	-	Semi-cont.	1.0	1.35
Ploeg	Chevron	Midway Sunset	Monarch	Semi-cont.	3.3	4.42

[1] First author of paper.

foam injection began. Substantial increases in oil production and improvement in oil-steam ratio were observed in all cases. However, a breakdown of the percent increase in oil production that is directly attributable to foam is difficult. Since Mobil oil is the largest volume user of surfactant for steam-foam, their success can be partly attributed to application of foam early in the life of their steamfloods. They have found a surfactant system that for them is cost effective in the geology, mineralogy, oil composition of their specific reservoirs. The estimated volume of surfactant used by Mobil is > 500,000 pounds per year.

Most current application of foam is for near well steam foam applications to improve or even out steam distribution in cyclic steam or early in the life of steam floods. These are usually low volume applications

To What Extent is the Industry Conducting Foam Research?

Currently, industry has little interest in foam technology research. Majors through contractors (service companies, surfactant suppliers, universities and to a small extent in-house) conduct laboratory flow studies to support their field activities. Fundamental foam research is currently confined to not-for-profit research institutes and academia.

What is the Future of Foam?

Unless heavy oil prices rise and stay > $20/bbl, majors are unlikely to implement any new steam-foam projects, except near-wellbore treatments in cyclic wells.

What Role Should DOE Play in Nurturing and Sustaining Foam Technology?

The DOE should promote several cost-shared long-duration (3 or more years) steam-foam projects in different fields to promote technical and economic viability of the process and to obtain field specific information. This information can be used to improve the technology, develop better steam-foam simulators, and formulate newer and better surfactants. The DOE should also continue to sponsor basic research on foam transportation mechanisms in porous media. Studies related to the minimization of surfactant losses by adsorption, partition and precipitation, and to the formulation of newer surfactants that are stable and effective over a wide range of reservoirs and operating conditions are recommended.

SUMMARY OF PANEL PRESENTATION AND DISCUSSION

As part of the foam symposium, a six-member panel with expertise in various aspects of field foam application was convened to discuss the current state of foam technology and to assess the future of field foam applications. To garner varied viewpoints on the status of foam technology, members were drawn from diverse interest groups. These included majors, chemical suppliers, service companies, academia, and not-for-profit research institutes.

Rod Eson of Enhanced Petroleum Technology Inc. chaired the session and served as the panel moderator. Other members of the panel included: Eric Waninger of Chevron Chemical

Company; Shane Mohammadi of UNOCAL; Ralph Cooke of Enhanced Petroleum Technology Inc.; John Heller of New Mexico Petroleum Recovery Research Center, and Laurier Schramm of Petroleum Recovery Institute.

The panel presentation and discussion, which lasted for 2 1/2 hours, was divided into three subtopics to allow discussion on the different facets of foam technology and to cater the varied interest of the audience. The topics discussed included the following:

Subtopic No. 1

(a) What characteristics make a good foaming agent?

(b) How do you test these characteristics?

(c) What reservoir and/or co-injection property beneficially or adversely affects the foam and whether the oil recovered is residual oil, incremental oil, or accelerated oil?

Subtopic No. 2

Foam simulation: Its importance or lack of it.

Subtopic No. 3

Field projects and how do you handle them?

Subtopic 1 was addressed by three members from the perspective of hydrocarbon-foam (Laurier Schramm), CO_2-foam (John Heller), and steam-foam (Eric Waninger). Shane Mohammadi of UNOCAL discussed the pros and cons of foam simulation (subtopic No. 2) and Ralph Cooke discussed the field implementation aspects of foam technology (subtopic No. 3).

The panel members presentation are summarized in the following paragraphs.

SUMMARY OF PRESENTATION BY LAURIER SCHRAMM

Dr. Laurier Schramm, who represented the Petroleum Recovery Institute (PRI) of Calgary, Canada, addressed the use of foam to control mobility in western Canadian hydrocarbon miscible floods. Some western Canadian basin reservoirs are characterized by the presence of connate waters that are high in hardness (25,000 ppm or higher as $CaCO_3$) and salinity (greater than 290,000 ppm NaCl). These values can be quite variable since many pools have been flooded with fresh water.

The characteristics of the surfactant that makes a good foaming agent for these environments are quite different from those used in steam-foam and CO_2-foam applications. A typical surfactant for use in hydrocarbon gas flooding of the harsh Canadian environments is one that is extremely hydrophilic, can tolerate the presence of high monovalent and divalent ion concentrations, possesses low rock adsorption characteristics, and exhibits good foaming ability in the presence of crude oil. High-temperature stability is desirable, but it need not be as high temperatures as are employed in steam-foam applications. Since very few of the commercially available surfactants were able to satisfy all of the above criteria, attempts were made to formulate surfactants to satisfy the requirements of specific reservoir environments. This proved to be an extremely difficult task. The requirement of low adsorption on reservoir rock was difficult to attain. The degree of adsorption was found to depend on surfactant structure, rock mineralogy, solution pH, salinity and hardness, temperature, residual oil saturation, and rock wettability. The foaming ability of the surfactant was found to depend on the nature of the crude oil present and on such foam lamella characteristics as surface elasticity, surface viscosity, and disjointing pressure. Many times a surfactant that exhibited good bulk foaming ability failed to perform well in ""standard" porous media (e.g., Berea sandstone). Furthermore, in some cases a surfactant that exhibited good foaming performance in Berea sandstone (or Indiana limestone) failed to perform as well in reservoir rock samples flooded at reservoir conditions. Dr. Schramm also pointed out that assessment of gas mobility reduction itself is beset with problems. The mobility reduction factors depend on not only the surfactant but also on the nature of the brine and porous medium, on foam quality and texture, and on the residual oil saturation and the nature of the crude oil. Thus, it can be extremely difficult to design a good and effective foaming surfactant for use in harsh western Canadian reservoir environments. However, when such a foam is found and applied, coreflood studies have shown it should not only improve reservoir sweep efficiency but also be effective in recovering incremental oil in the range of 2 to 10% beyond the waterflood residual oil recovery.

SUMMARY OF PRESENTATION BY JOHN HELLER

Dr. John Heller, a Senior Scientist at the New Mexico Petroleum Recovery Research Center, outlined the surfactant requirements for CO_2 foam use. These, in many respects, are similar to those for surfactants used in the hydrocarbon foam application. Briefly, the surfactant (a) must be compatible with the chemical and thermal environment of the reservoir; (b) must exhibit low adsorption characteristics on the reservoir rock; (c) should exhibit minimal solubility in the oil or in dense CO_2; and (d) must produce relatively long-lasting foam in the presence of the crude oil. Surfactants formulated to satisfy these requirements are currently being field tested for their effectiveness in lowering the mobility of CO_2; to reduce the flow of CO_2 in high-permeability regions of the reservoir, and to produce incremental oil.

SUMMARY OF PRESENTATION BY ERIC WANINGER

Eric Waninger of Chevron Chemical Co. detailed the requirements of a good foaming surfactant from the steam-foam application perspective. These requirements were as follows:

1. The surfactant must be inexpensive and compatible with the reservoir environment.
2. The injected surfactant must be able to sustain its foaming ability over a wide temperature range. In steamflood application, the temperature will likely vary from about 250° F for a very low-pressure steaming operation to about 550° F for high-pressure operation.

3. The surfactant must be compatible with the liquid volumes that they are likely to encounter in the reservoir. The surfactant concentration may range from 0.3 to 2%, depending upon the quality of steam injected.
4. Since the foaming ability of the surfactant and the foam stability depend upon crude oil composition, laboratory tests must be performed to assure foamability and estimate the desirable surfactant concentration.
5. Although injection of foaming surfactant into the reservoir results in additional oil production, quantification of this additional production into residual, incremental or accelerated oil is not possible.

SUMMARY OF PRESENTATION BY SHANE MOHAMMADI

Dr. Shane Mohammadi, a senior scientist at UNOCAL, addressed the issues associated with the simulation of steam-foam processes. In particular, he discussed the following topics: (1) validity and reliability of steam-foam simulation studies; (2) primary factors controlling the propagation of foam in the reservoir and can the simulator be used to predict the effect of these parameters on process behavior; and (3) can the pilot steam-foam history match results be used to predict the field-wide steam-foam performance?

Simulators are reservoir management tools that can be used to improve the understanding of foam flow behavior in the reservoir and increase the odds for successful completion of a steam-foam project. Simulators have been used since the mid-80s with some success to capture certain features of successful steam-foam pilots. The currently available commercial steam-foam simulator employs semi-empirical correlations to model surfactant propagation in porous media and to simulate the dynamics of foam generation and decay. The empirical nature of the model usually precludes accurate history match, and engineering judgment is critical in the interpretation of results and in future performance prediction. Nevertheless, the simulator has been used successfully to confirm the field observations in a Midway-Sunset (CA) steam-foam pilot. Because of the incomplete understanding of foam transport mechanism in the porous media and the complex nature of the steam-foam drive process, empiricism in steam-foam simulation practice is likely to be continued for the foreseeable future.

The primary factors controlling the rate of foam stability and propagation include surfactant type and concentration, surfactant loss mechanism (adsorption into rock, partition into oil and precipitation), reservoir salinity, matrix permeability and capillary effects. Simulation studies indicate that steam-foam simulators can predict qualitatively the effect of these factors on the process behavior.

Recently, existing steam-foam simulators have been validated using simplified reservoir prototypes and limited field pilot data. Validation at a more complex level (i.e., multi-pattern simulation) has not been attempted. Multi-pattern steam-foam recovery is a slow and complicated process and under today's economic climate, it is difficult to justify any significant effort to perform this task. Once validation at more complex levels has been completed, the simulator can be used for process optimization. For example, improved formulation of surfactants can be studied and evaluated on various techniques for surfactant injection.

SUMMARY OF PRESENTATION BY RALPH COOKE

Ralph Cooke of Enhanced Petroleum Technology Inc. discussed the techniques used in the field to evaluate the effectiveness of steam-foam treatment and their shortcomings.

Steam-foam treatment is a low-cost chemical heat diverter technique, principally employed in cyclic steam stimulation wells to correct apparent steam distribution (poor injection profile) problems. Steam-distribution problems arise in cyclic operations conducted in massive unconsolidated heavy oil-bearing sands (such as the Potter sand of Midway-Sunset field) where gravity drainage is the major producing mechanism.

Steaming operations in such reservoirs results in localized depletion of oil from the upper portions of the sand. During subsequent cycles, steam tends to seek oil-depleted zones, resulting in poor production. Steam-distribution problems in cyclic stimulation are corrected by injecting an aqueous solution of a high-temperature foaming surfactant. The surfactant converts to a stable foam on contact with steam in the depleted zones and helps redirect steam from areas of gravity override into portions of the reservoir containing greater oil saturation. As the reservoir (steam) temperature drops below 200° F, the foam converts back to a liquid and is produced with the reservoir fluids.

Some of the signs watched for in the field to confirm the success of a steam-foam treatment are: (1) increase in the tubing pressure over the average pressure prior to the treatment; (2) an increase in oil production in comparison to the expected production without the treatment; and (3) temperature-tracer surveys before and after treatment to confirm the diversion of steam into a zone that had not been contacted before.

While an increase in the flow line (tubing) and casing pressures are indicators of diverter success, pressure increase does not necessarily confirm diverter success. The results from several individual wells treated with foam diverters indicate large pressure increases without corresponding increases in oil production. In fact, some of these wells showed a decline in production. Similarly, there are cases of steam-foam treatment projects that have shown substantial increases in oil production without any increase in wellhead (tubing) pressure.

Further, production of incremental oil in wells treated with foam diverters does not necessarily confirm the diverter success. In many cases, changes made in steam rates, steam qualities, production interference from the stimulation of adjacent wells, etc., can cause production to increase. It is imperative that the effect of these factors be discounted from the determination of incremental oil due to foam treatment.

In assessing the success of a foam treatment, all of the aforementioned "watched for signs" must be considered. If one or more of these signs are not present, changes must be made to the treatment methods. These may include lowering the steam quality, changes in surfactant concentration, changes in the mode of application (for example, switching from continuous to semicontinuous application), changes in the frequency of application, etc. Thus, careful monitoring of steam-foam diversion treatment is critical to the economic success of the program.

PANEL DISCUSSION

Following the panel presentation, the session was opened for discussion. Selected questions from the symposium participants and the panel members responses are summarized in this section.

Question to Audience from Rod Eson

One of the panel members (Laurier Schramm) expressed his inability to relate laboratory tests of foam conducted on clean porous media results with those obtained using reservoir rock. Everyone I know do tests in the laboratory with Berea sandstone. Is there any real value in this kind of test? Why work with them if they do not relate to the field?

Comments from Louis Castanier, Stanford University

In the steam injection process study, all work was done in clean sand and good laboratory work under controlled conditions is good and should not be ridiculed. Most of the initial screening of surfactants for steam-foam application was done on clean sand and porous media and most of the observations are still valid, even though not necessarily correlated with field results. Good laboratory work under controlled conditions can provide us with useful information for the design of field projects.

Comment by John Heller, New Mexico Petroleum Research Center

Using a well characterized system, you can test and determine how foam forms and how it propagates in porous media. Laboratory tests shed light on the physics of foam formation and propagation in porous media and this information is critical to the development of foam simulators.

Question to Shane Mohammadi, UNOCAL

What is the validity of steam-foam history matching when you do not have a very good scientific understanding of what is going on in the reservoir?

Reply

I did not cover in-depth the current state of the steam-foam simulation. On a small laboratory scale, simulators are available that account for population balance of lamellae and address other mechanistic issues. But due to the complexity of computation and because on a field scale we are not sure what happens to these foam lamellae, the industry has adopted a different modeling approach to the development of field-type simulators. The approach that UNOCAL, as well as others in the industry have taken, is the semi-empirical approach. Because of this, the steam-foam simulation (for that matter any field level simulation) must be performed by a knowledgeable person. When you try to simulate any type of process, you really have to know the process and do some experiments to assist in history match. Also, I want to address the criticism that anyone can history match production by fiddling with parameters and call it a solution. Anyone in the audience who has significant simulation experience, whether it is black oil, compositional or any other process, knows that the history matching process is a frustrating and tedious chore. You cannot fudge one or more parameters such as the relative permeability to obtain a match and call it a solution. To history match you have to know your field and be able to zoom in on the actual solution to your problem for the time period you are interested in. No, history match is not an open field where every knob is available to you to turn. A knowledgeable person who is able to history match 30 years of production by judiciously adjusting selected parameters and then make a production prediction for the next 10 years, has done a pretty good job. My point is that steam-foam history match has validity if done properly by a person who knows the process.

Comments by Tad Patzek, University of California, Berkeley

Reservoir simulation is nonunique. This stems from the basic fact that the pressure equation that you are trying to solve is a diffusion equation, which means there is no unique solution. For example, Shell in their earlier approach to foam simulation employed the population balance technique to understand the basic physics of foam flow in the porous media. Though it has a theoretical foundation, it is very difficult to describe mathematically and solutions cannot be found except for very simple ideal cases. On the other hand, to simulate the Bishop steam-foam pilot, we (Shell) restored to empiricism because we do not understand the physics in 3-dimension. All we did to simulate the pilot was to maintain the mass balance on the surfactant. We then looked at the foam propagation in the field pilot and adjusted the rate of propagation of surfactant in the simulator so as to match the average rate of propagation of foam in the field. The surfactant propagation rate in the simulator was varied by adjusting the surfactant partition coefficient. Thus, we have only one knob to play with. This then reflected all the first-order characteristics of the system. We were able to do a reasonable job in matching everything else by adjusting this one knob. I am very weary of multiple knob models in which people who do not know how to perform a simulation, blindly turn several knobs, come up with a solution, publish it, and call it a history match. There is one more point I want to make. Under the present economic climate, I do not anticipate industry to spend (certainly not Shell) any money in the research and development of a basic foam model. So the second best solution as pointed out by Shane is the use of semi-empirical models to describe foam propagation. I think it is the only practical solution, and I do not foresee anything else.

Question to Shane Mohammadi, UNOCAL

How much faith do you have in your simulation results and how well can you match field data when you do not know how far into the reservoir the foam moves and the characteristics of the reservoir?

Reply

I think your question applies to simulation as a whole, regardless of whether it is foam simulation or thermal simulation or any other type of simulation. To the extent that industry has accepted the role of simulation in the decision-making process and believe me we are putting platforms out in the ocean based on the outcome of these simulation results, I think I can say confidently that industry has faith in simulation. Having accepted that, I say let us see whether we can push it one step further and apply it to predict foam pilot test outcome. This is essentially testing its validity. You are absolutely right in your comment regarding whether simulator results are valid. I think the industry has pretty much accepted them as a reservoir management tool, and I personally have accepted them. As an example, we have made significant progress in 3-D seismic data processing, and the industry is in the process of including 3-D seismic data into the simulator to better describe the reservoir. How soon we can do this and how successful we can be is not known at this time. Until then you have to exercise caution and use engineering judgment in the interpretation of foam simulation results.

Question from Rod Eson to Shane Mohammadi

In your presentation you said that you satisfactorily history matched your 9-day mini steam-foam pilot test (S. Casper Creek, WY, Mini-Foam Test) and used the results to predict reservoir response to a 6-month-long foam injection project. Making such a long-term projection based on the results of a short-duration test involves a certain leap of faith. In simulation, the result is only as good as your input data. In the 9-day mini test all you did was to lower the steam injection rate and raise the wellhead pressure. The duration of the test is too short to confirm the oil production response changes. Given such minimal project information, my question is can you confidently predict long-term reservoir response based on short-duration results?

Reply

You are absolutely right. In 9 days all you are doing is pressuring up the well, indicating that foam had been formed near the wellbore. It was argued that if steam is diverted away from the observation well, then the concentration of total dissolved solids in the produced water from the observation well should increase and approach that of the formation water. We observed this trend, verifying that steam diversion had occurred. The point I am trying to make is that if I can history match satisfactorily the short-duration test observations, then to me it is an indication that the simulator is capable of describing the foam propagation effect in the reservoir, and the predicted results are going to be close to what I will actually observe had I prolonged the test for 6 months. I cannot vouch for it. The next step should be the history match of our 3-year steam-foam project in Dome-Tumbardor. I understand DOE is sponsoring a project at NIPER to do this. That will then make it clear whether the simulator can do the job and predict steam-foam performance. As a designer, I have faith in the simulator, and I believe it will work. Somebody has to prove it.

Question to Eric Waninger, Chevron Chemical

When you do a steam-foam project in the field, how do you determine that the foam is working?

Reply

In all the successful projects (economically successful projects) I am associated with, we have seen an increase in wellhead pressure. That is the first thing I look for.

Comment from Louis Castanier, Stanford University

Pressure increase is not necessarily an indication of success. There are documented case histories that showed substantial increases in oil production (over 1,000 bbl/d) but did not show any increase in wellhead pressure. Some other mechanism is at work. Pressure increase does not necessarily translate to economic success. There are also cases where substantial wellhead pressure increase was observed, but no significant increase in the total oil recovery.

Comment from Shane Mohammadi, UNOCAL

Let me comment on Louis' observation. In the past, back in the mid-80s, there was a tendency on the part of the chemical suppliers to come up with a multicomponent type foaming agent designed to cause wellbore pressure increase. For example, it combines linear toluene sulfonate with some caustic in order to raise the pH and make they foam better. We tested some of these formulations. A particular formulation that comes to mind, is called "Suntech IV-FA." This particular surfactant, when tested in the field, showed phenomenal wellhead pressure increase. Soon after, when the test was completed, we saw no increase in oil recovery. In fact, the oil production went down. When we analyzed the data, we realized that the caustic in the surfactant was consumed by the reservoir rock. The surfactant by itself was not an effective foamer. One should make sure that the foamer used is compatible with the reservoir rock.

Comment from Eric Waninger, Chevron Chemical

I concede that increase in wellhead pressure does not mean success, but in all the projects I am associated with I saw at least a minimal increase in wellhead pressure. Increase in the wellhead pressure is not the only sign I look for. In steam-foam drives, often another fairly immediate thing we look for is the reduction in casing effluent production. In successful steam-foam projects, steam production at your production well goes down. That is an indication that foam blocks the high-permeability channels. When you notice a very abrupt change in casing heat production (and this happens quickly, often within a month of injecting the surfactant), it is an initial indication that the foam is doing what you wanted it to do. Another thing you can do is to run an injection profile test. After a few days of surfactant injection, run a krypton or other radioactive tracer survey, and you should notice the change. If you do not see any change, a redesign of the project may be recommended.

Comment from Todd Reppert, Exxon Production Research

I disagree. A reduction in casing heat production does not mean foam is blocking a thief zone or a channel. Foam blocks anything it can block near the injector, not necessarily a particular channel. What happens is as you increase the injection pressure for a while, the injected steam moves into the reservoir where it encounters a colder formation, so it condenses. This decreases your inflow of steam to your producer and increases the pumping efficiency. You see a decrease in casing heat production and increase in oil production due to increased pumping efficiency.

Question to Eric Waninger, Chevron Chemical

How do you know where the foam is in the reservoir and its effect on the flood?

Reply

No one can tell where in the reservoir the foam is located. Perhaps a simulation study would provide the best answer. Through simulation I have seen excellent matches of field observation. Since we know the adsorption characteristics of surfactant and rock, we can estimate the surfactant loss due to adsorption and have an idea of how far the surfactant can propagate. If you have temperature observation wells, and if you see the well temperature goes up and many times these wells also produce surfactant; this is an indication of the location of a foam bank in the reservoir. An increase in oil production hopefully is also an indication of the effectiveness of foam.

Question to Eric Waninger, Chevron Chemical

What corrective action will you implement if you do not see any visible sign indicating that the foam is working?

Reply

There are several things one can do if foam is not doing what we think it ought to do. If you see no pressure response upon injecting foam forming surfactants into a well, inject surfactant at a higher rate or increase the surfactant concentration. If you still see no pressure response, increase the liquid volume fraction by lowering either the steam quality or adding water into the steam line at the wellhead. More than likely you will see a pressure response. Our experience in the laboratory and in the field indicates that the ability of a surfactant to form foam is more sensitive to liquid volume fraction than to surfactant concentration.

Question from Terry Osterloh, Texaco

Throughout the day I got the impression that it is better to get the foam out as far into the reservoir as you possibly can, but in terms of optimizing the economics of the process that is not necessarily true. Has anyone looked into that?

Reply by Eric Waninger, Chevron Chemical

Yes, it has been looked at pretty thoroughly by the industry. If you have a stratified reservoir with well defined shale-sand sequence and you want to correct the injection profile problem in that reservoir, it can be accomplished cost-effectively by injecting slugs of low concentration foaming chemicals. When you inject low concentration chemicals, it will alter the injection profile near wellbore, but the foam will not move very far away from the wellbore due to adsorption into the rock. For foam to propagate out into the reservoir you have to inject large volumes of chemical.

Question from Terry Osterloh, Texaco

You modified the vertical profile for a number of layers and stopped. Is that an economical optimum thing to do?

Reply by Eric Waninger, Chevron Chemical

That depends on a lot of things. If you have a well that has been completed in a certain way and cannot change it, then you may be correct. What is optimum in one case may not even be a solution to another case. You have to ask what your alternatives are and seek the best solution. The best solution is not necessarily an optimum.

Question from Terry Osterloh, Texaco

But in terms of gravity override, can you afford to put enough surfactant in the reservoir to solve that problem?

Reply by Shane Mohammadi, UNOCAL

I would like to comment on the question whether you can afford to stop gravity override by injecting foam. Between the year 1986 to middle of 1989, UNOCAL injected foam continuously into four injectors in Midway-Sunset field. Now I can furnish some dollar amounts on that project. To the best of my recollection, UNOCAL spent something close to 2 million dollars on that project. This included cost of chemicals, surface facilities, and other operations expenses. During that time, the heavy oil was selling at about $18/bbl, and gradually falling. Early on in the project, we were able to recover a lot of the so-called accelerated oil and cash-in on high oil price. We made a profit on that project. Toward the end of the project, when incremental oil production was low, the oil was selling at about $11/bbl. That is when we decided to terminate the project. For the whole project, I think we made about $3.2 million. For an income like that, the project was well worth it. We were able to mitigate the gravity override problem by injecting large quantities of surfactant. But at today's oil price, the project may not be economical. If the price of the oil is say $20/bbl or more, we will consider implementing the project again. The bottom line is that if the price is right you can afford to inject surfactant to solve gravity override or any other problem associated with steamdrive.

Question by Eric Waninger, Chevron Chemical

What effect do the cheaper chemicals have on decision making?

Reply by Shane Mohammadi, UNOCAL

The problem right now, especially in the San Joaquin Valley steaming operations, is that you can barely make any money. If you can barely make money out of your steam operation, it is impossible to go to management and propose a project that has a front end cost of the order of about $400,000 for surface facilities and additional half a million dollars worth of chemical. Irrespective of whether the chemical is cheap or expensive, it will be a hard sell under the current economic climate.

Comment by Jerry Casteel, DOE

I would like to make a comment here. I am Jerry Casteel from U.S. DOE and we are currently funding a project in New Mexico on profile modification with gel. This may find an application in a steamdrive reservoir, if we can design a temperature insensitive gel. One of the things we found was profile modification does more harm than good. Simply injecting a profile modification chemical into the well and allow it go where it wants to go may not be the best thing to do. Monitoring the project is critical to confirm the diverting character of the chemical and take corrective action, if needed. You may inject a gel and get a pressure response and think you are doing okay, but in fact you are not okay. Because you get crossflow and everything else in the reservoir you may be fooling yourself. Unless you do a zonal isolation to ensure that the chemical is going where you wanted it to go, you may be out of luck.

Question by Rod Eson, Enhanced Petroleum Technology

To wrap up this panel discussion session, I want to throw in one final question to the participants and panel members. The question is though foam technology is proven to be both technically and economically viable, why aren't more people doing this in the field? I would like your personal opinion, not your company's position. I would like the audience to answer first, and then the panel members. Keep your comments brief please.

Comment by Tad Patzek, University of California, Berkeley

I contributed to steam-foam research at Shell and no doubt my work contributed to the success of Shell's steam-foam pilot. I can tell you the reason why many steam-foam projects are not being implemented. There is no such thing as a generic steam-foam process. Every steam-foam project is unique and must be tailored to a particular reservoir. Each company or corporation inventories its portfolio of reservoirs and seeks processes that are applicable to those reservoirs. In the case of Shell, it is steam. Since Shell has started steam projects much earlier than other operators, its thermal projects are nearing their economic limit. The projected recovery from Shell's steam projects are very high on the order of 70% or more of OOIP. Therefore, at the moment you are proposing a steam-foam project in a matured reservoir where steamflood proved to be very efficient. You are trying to compete against a very efficient and cheap process and going after an oil that is very difficult to recover. Even though we have shown that steam-foam processes can economically recover incremental oil, it was disregarded because the rate of return from steam-foam projects from Shell's point of view does not meet its corporate objectives.

Comment by Rod Eson, Enhanced Petroleum Technology

It is a catch-22 situation and is true for any EOR process. If you start early, you can make money, but convincing management to start the project early is nearly impossible.

Question by Eric Waninger, Chevron Chemical

Is the price of surfactant derailing the project economics?

Reply by David Hutchison, Shell Western E&P

That is correct. In Shell's case, the operating personnel were going after continuous surfactant injection. This increased the cost of steam-foam pilot. Most of the steam-foam projects are only marginally economical. The incremental profit over and above the well-conceived and well-run steamdrive projects were less than acceptable to management, and under such situations it is difficult to convince management to commit funds for additional projects.

Comments from Nizar Djabbarah, Mobil

Under today's economic climate, you cannot afford to inject surfactant continuously to produce incremental oil. You have to balance the value of surfactant injected to the value of oil produced. Mobil had very good success in recovering oil with steam-foam in the Tulare. The reason for that is we have a very good understanding of surfactant, rock interaction and the losses due to adsorption were more favorable than in other formations. The geology of Tulare is such that there is connectivity between flow channels and the foam is able to block thief channels. Surfactant that works best in one area may not work in another area. You have to take your time and evaluate the surfactants for that specific reservoir and specific injection and well completion scheme. You must base your economics on surfactant type, steam quality, steam injection rate, and expected additional recovery. If you keep your surfactant injection rate constant or surfactant, concentration same throughout the life of a project, it probably is not going to be economical. Since steam quality and injection rate varies from day-to-day, keeping surfactant injection rate or surfactant concentration constant is not going to be beneficial. You have to have a good understanding of potential surfactant losses and the effect of steam quality on the surfactant formability to do an effective job. You have to do your homework well ahead and move cautiously. If you do that, chances are the project will succeed. Coming to the main question, will Mobil continue steam-foam projects, I will say no. Steam-foam projects are manpower intensive and involve a lot of leg work. and the current economic conditions do not justify that.

Comments from Shane Mohammadi, UNOCAL

I would like to offer an explanation for why I think the managements of many oil companies are not supporting this type of work to the extent they should be and also offer a suggestion as to how you can get around that.

In my opinion, foam technology, whether it is applied to steam, CO_2 or hydrocarbon miscible drive, is truly a tertiary recovery process. The object of the foam process is to recover the oil left behind by steam or CO_2 or what not. The management and operational personnel of most oil companies are very comfortable with primary production and somewhat comfortable with secondary recovery operations, but skeptical with tertiary recovery. Part of the skepticism arose from the failure of tertiary recovery processes such as the chemical flooding of the 1970s. Foam is a truly tertiary process, and there are risks involved in implementing it. When I started my career in foam, I was under the impression that here is a substance that is primarily gas and I am only using very little chemical to generate large volumes of foam and arrest mobility. In reservoirs, we are dealing with huge pore volumes, and foam is the only substance that can cost-effectively plug the depleted zone and improve volumetric conformance. I am still convinced foam technology has a much better chance of acceptance than some other exotic techniques we have developed over the years.

Now, let me explain how we can convince management to go along with doing a project like this. First, identify the problem areas in the field, wherever that may be. Then at a very low level, say at the engineering supervisory level, propose some sort of small duration test. The cost of the project must be very minimal. At the same time, make sure what you are proposing is likely to succeed and you have a good understanding of it. For example, we proposed and implemented a 9-day mini steam-foam test and demonstrated to the management, the viability of the project. Once you have established the viability of your mini project, go ahead and propose a short-duration expansion, say a 6-month project. Keep your fingers crossed and hope that towards the end of 6 months you have some positive results. If you do, then you can expand your expansion. This is exactly what we did with one of our major steam-foam project. The original project was designed to be a 6-month experimental project, but we continued it on for 3 1/2 years. We were able to do that because we showed positive results at the end of each year and the management was willing to funnel additional money into the project. The project was highly profitable to the company. Thus, the key to a successful project is to start small and expand as you go along. In my opinion, this is the only way to overcome management's skepticism on tertiary recovery projects.

Comment from Rod Eson, Enhanced Petroleum Technology

Let me offer my views before bringing today's session to a close. I have been associated with steam-foam technology for almost 20 years, the last 13 of which was in sales, design, and implementation of the process. In my opinion, none of the explanations offered by previous speakers satisfactorily answer the question. The technical and economic viability of steam-foam technology have been well established. As Nizar (Djabbarah) pointed out, economic success can be assured by careful design. Politics, more than economics, is the primary reason why we are not seeing many steam-foam projects. Because of low oil prices, oil companies have slashed their staffs and moved people around. Engineers, who have escaped the ax, are under pressure to show profit. Their bonus depends upon keeping the operation in the black. So, the engineers are less willing to take a risk. If we do succeed in getting a project approved and by the time we complete the design and are ready to implement it, the engineer who approved it is not around. I can name dozens of projects where we have gone through this—when a new engineer who is responsible for implementing the project comes along, they are reluctant to spend the money. If he implements the project and by the time the project bears the fruit he is not going to be around to collect his bonus. So there is no incentive for him to spend the money.

REFERENCES

Castanier, L. M. and W. E. Brigham. An Evaluation of Field Projects of Steam With Additives. Pres. at the SPE International Meeting on Pet. Eng., Beijing, China, Nov. 1-4, 1988, pp. 883-892. SPE paper 17633.

Chiang, J. C., S. K. Sanyal, L. M. Castanier, W. E. Brigham and A. Sufi. Foam as a Mobility Control Agent on Steam Injection Process. Pres. at the SPE California Regional Meeting, San Francisco, March 1982. SPE paper 8912.

Doscher, T. M. and E. G. Hammershaimb. Field Demonstration of Steam Drive With Ancillary Material. J. of Pet. Tech., July 1982, pp. 1535-1542.

Doscher, T. M., V. A. Kuuskraa and E. C. Hammershaimb. Analysis of Five Field Tests of Steamdrive Additives. Pres. at the SPE Annual Meeting, San Francisco, CA, October 1983. SPE paper 12057.

Eson, R. L. and R. W. Cooke. A Comprehensive Analysis of Steam Foam Diverters and Application Methods. Pres. at the SPE California Regional Meeting, Bakersfield, CA, Apr. 5-7, 1989. SPE paper 18785.

Farrell, H. H., L. B. Plumb and P. H. Lowry. An Evaluation of the Field Demonstration of the Conventional Steam Drive Process With Ancillary Materials at North Kern Front Field. Pres. at SPE California Regional Meeting, San Francisco, April 1985. SPE paper 10775.

Greaser, G. R. and R. A. Shore. Steamflood Performance in the Kern River Field. Pres. at SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, OK, April 1980. SPE/DOE paper 8834.

Hirasaki, G. J. The Steam-Foam Process. J. Pet. Tech., v. 41, May 1989, pp. 449-456.

Malito, O. P., S. K. Sanyal and W. E. Brigham. A Field Experiment of Steam Drive with In-Situ Forming. Second Annual Report, Oct. 1, 1982-Sept. 30, 1982. Stanford University Petroleum Research Institute, Stanford, California.

Mohammadi, S. S. and T. J. McCollum. Steam-Foam Pilot Project in Guadalupe Field, California, SPE Res. Eng. J., February 1989a, pp. 17-23.

Mohammadi, S. S., D. C. Van Slyke and B. L. Ganong. Steam-Foam Pilot Project in Dome-Tumbador, Midway-Sunset Field, SPE Res. Eng. J., v. 1, February 1989b, pp. 7-16.

Olsen, D. K. Thermal Processes for Heavy Oil Recovery, U.S. Dept. of Energy Report No. NIPER-436, September 1989.

Patzek, T. W. and M. T. Koinis. Kern River Steam Foam Pilots. Pres. at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, OK, Apr. 17-20, 1988. SPE/DOE paper 17380.

Ploeg, J. F. and J. H. Duerksen. Two Successful Steam-Foam Field Tests, Section 15A and 26C, Midway-Sunset Field. Pres. at the SPE California Regional Meeting, Bakersfield, CA, Mar. 27-29, 1985. SPE paper 13609.

Yannimaras, D. V. and R. K. Kobbe Evaluation of Steam-Surfactant-Fuel Gas Co-Current Injection Into the Patterns of a Mature Steamflood. Presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, OK, Apr. 17-20, 1988. SPE/DOE paper 17382.

APPENDIX
LIST OF SYMPOSIUM ATTENDEES

Adamache, Ion
Adamache Petro Eng. Ltd.
Apt. 908
330 26 Ave. SW
Calgary, Alberta
Canada T2S 2T3

Bain, George F.
Chevron Chemical Company
5001 California Ave.
Bakersfield, CA 93309

Beattie, Craig I.
Imperial Oil Resources Ltd.
3535 Research Road, N.W.
Calgary, Alberta
Canada T2L 2K8

Bird, Gordon
Alberta Research Council
P.O. Box 8330, Postal Station F
Edmonton, Alberta, Canada T6H 5X2

Boberg, Thomas
311 Electra
Houston, TX 77024

Brigham, William E.
Petroleum Eng. Dept.
Stanford University
350 Mitchell Bldg.
Stanford, CA 94035-2220

Busby, Joel
Mobil
P.O. Box 633
Midland, TX 79707

Carson, Jacquiline D.
Chevron Chemical Co.
601 Bollinger Canyon Rd.
San Ramon, CA 94583

Castanier, Louis M.
Petroleum Eng. Dept.
Stanford University
350 Mitchell Bldg.
Stanford, CA 94035-2220

Casteel, Jerry F.
DOE/BPO
P.O. Box 1398
Bartlesville, OK 74005

Chou, S. I.
Chevron Oil Field Research
P.O. Box 446
La Habra, CA 90633-0446

Cooke, Ralph W.
Enhanced Petroleum Tech. Inc.
P.O. Box 212
Bakersfield, CA 93302

Dalland, Mariann
Rogaland Research
P.O. Box 2503 Ulandhaug
N-4004 Stavanger, Norway

De Paz, Miriam Lopez
Lagoven S.A.
P.O. Box 172
Maracaibo, Venezuela

Djabbarah, Nizar
Mobil R&D
P.O. Box 819047
Dallas, TX 75381

Eson, Rod
Enhanced Petroleum Tech. Inc.
P.O. Box 212
Bakersfield, CA 93302

Evans, E. M. (Gene)
Mobil Oil Corporation
P.O. Box 633
Midland, TX 79702-0633

Flor, Gutierrez, Secretary
Empresa Nacional Del Petroleo
New York Office, Suite 5151
One World Trade Center
New York, NY 10048-0497

Forst, Harry F.
Chevron Chemical Company
P.O. Box 2449, Suite 400
Houston, TX 77252-2449

Gangle, Francis J.
DOE
P.O. Box 11
Tupman, CA 93278

Gdanski, Rick
Haliburton Services
605 Fielderest
Duncan, OK 73533

Giangiacomo, Leo
FD Services, Inc.
907 N. Poplar, Suite 100
Casper, Wyoming 82601

Gonzales, Sandy K.
ARCO Oil & Gas Company
P.O. Box 147
Bakersfield, CA 93302

Handy, Lyman
University of Southern California
Petroleum Engineering Program
Chemical Engineering Dept.
HEDCO 316-University Park
Los Angeles, CA 90089-1211

Hanssen, Jan Erik
Rogaland Research
P.O. Box 2503 Ulandhaug
N-4004 Stavanger, Norway

Heller, John
Petroleum Recovery Research Center
Socorro, New Mexico 87801

Hendricks, Marvin L.
Dept. of Energy
907 N. Poplar, Suite 150
Casper, WY 82601

Henry, Richard
Amoco Research Center
Box 3385
Tulsa, OK 74102

Herrmann, Daniel
FD Services Inc.
907 N. Poplar, Suite 100
Casper, WY 82601

Hoang, Viet T.
Chevron Research and Technology
6001 Bollinger Canyon Rd.
San Ramon, CA 94583

Hoeffner, Mark
MEPTEC
Box 819047 (zip 75381)
13777 Midway Rd.
Dallas, TX 74243

Honstein, Glen
Bechtel Petroleum Op., Inc.
P.O. Box 116
Tupman, CA 93276

Hosein, Aleem
Tritoc Ltd.
Pointe-a-Pierre
Trinidad

LIST OF SYMPOSIUM ATTENDEES—Continued

Hutchison, David A.
Shell Western E&P
5060 California Avenue
Bakersfield, CA 93309

Idol, Keith
Exxon Production Research Co.
P.O. Box 2189
Houston, TX 77252-2189

Isaacs, Eddy
Alberta Research Council
P.O. Box 8330, Postal Station F
Edmonton, Alberta
Canada T6H 5X2

Joubert, Geovanny
Lagoven S.A.
P.O. Box 254
Maturin, Monagas, Venezuela

Kovscek, Anthony R.
University of CA/Berkeley
201G Gilman Hall
Berkeley, CA 94720

Kuehne, Don
Chevron Research & Technology
100 Chevron Way
Richmond, CA 94802-0627

Leong, John K.
UNOCAL
1800 30th Street, Suite 200
Bakersfield, CA 93301

Lim, Frank H.
Union Pacific Resources
P.O. Box 7
Fort Worth, TX 76101

Mahmood, Syed
NIPER
P.O. Box 2128
Bartlesville, OK 74005

Martin, Jim
Bechtel Petroleum Op., Inc.
P.O. Box 116
Tupman, CA 93276

Mendez, Zuleyka
INTEVEP S.A.
Los Teques, Edo. Miranda
Apdo. 76343
Caracas 1070A, Venezuela

Milter, Jess
Improved Recovery Group
Rogaland Research
P.O. Box 2503 Ulandhaug
N-400 Stavanger, Norway

Mohammadi, Shane
UNOCAL
P.O. Box 76
Brea, CA 92621

Olsen, David K.
NIPER
Box 2128
Bartlesville, OK 74005

Osterloh, Terry
Texaco EPTD
P.O. Box 770070
Houston, TX 77215-0070

Papir, Joe
Chevron Chemical Co.
6001 Bollinger Canyon Rd.
San Ramon, CA 94583

Patzek, Tadeusz
University of California, Berkeley
Chemical Eng. Dept.
Berkeley, CA 94720

Prieditis, John
Texaco Inc. EPTD
3901 Briarpark
Houston, TX 77042

Puerto, Maura C.
Exxon Production Research
P.O. Box 2189 (zip 77252-2189)
2015 Briarstem
Houston, TX 77077

Radke, Clayton J.
University of CA/Berkeley
Chemical Engineering Dept.
Berkeley, CA 94720

Reid, Thomas B.
DOE/BPO
P.O. Box 1398
Bartlesville, OK 74005

Reppert, Todd
Exxon Production Research
3120 Buffalo Speedway
Houston, TX 77098

Rossen, William
The University of Texas at Austin
Dept. of Petroleum Engineering
Austin, TX 78712-1061

Sarathi, Partha
NIPER
P.O. Box 2128
Bartlesville, OK 74005

Schramm, Laurier L.
Petroleum Recovery Institute
100, 3512-33 Street N.W.
Calgary, Alberta, Canada T2L 2A6

Smith, Michael
Chevron Petroleum Technology Co.
1300 S. Beach Blvd.
La Habra, CA 90631

Soroko, Daryl
Saskoil
1777 Victoria Ave.
P.O. Box 1550
Regina SK, Canada S4P 3C4

Stevens, Jim
Phillips Petroleum Co.
E&P
North America Division
4001 Penbrook
Odessa, TX 79762

Stowe, G. R. III
Drilling Representative
Chevron U.S.A. Inc.
6004 Ambergrove Street
Bakersfield, CA 93313

Strycker, Arden
NIPER
P.O. Box 2128
Bartlesville, OK 74005

Sugiauto, Steve
Saskoil
1777 Victoria Avenue
P.O. Box 1550
Regina SK, Canada S4P 3C4

Talley, Larry D.
Exxon Research & Engineering Co.
P.O. Box 4255
Baytown, TX 77522-4255

Teletzke, Gary
Exxon Production Research
P.O. Box 2189
Houston, TX 77252-2189

LIST OF SYMPOSIUM ATTENDEES—Continued

Waninger, Eric
Chevron Chemical
P.O. Box 1392
Bakersfield, CA 93302

Welch, Robert A.
NIPER
P.O. Box 2128
Bartlesville, OK 74005

Weyland, Ginny
DOE
Box 11
Tupman, CA 93278

Williams, Richard L.
Santa Fe Energy Resources
5201 Truxtun Avenue, Suite 100
Bakersfield, CA 93309

Yortsos, Yanis C.
USC, Dept. of Chemical Engineering
HEDCO 316, University Park
Los Angeles, CA 90089-1211